Demand Response:
Principles for Regulatory Guidance

Prepared by

Peak Load Management Alliance

February, 2002

Acknowledgements

This policy paper developed under the active leadership of Ross Malme, Chair of the Peak Load Management Alliance, Joel Gilbert, Vice-Chair and Dan Violette, project leader and key author. Larry Barrett served as principal researcher, facilitator, and writer.

In addition to these contributors, an informal committee provided many significant contributions covering a variety of perspectives. These included: Aaron Bridenbaugh, Rick Berryman, Greg Bullington, Angela Chuang, Ed Cooley, Don Gilligan, Steve Fernands, Dal Fransden, Don Fuller, Rick Hornby, Leland Keller, David Lawrence, Joe Leccese, Paul McCurley, Sarah McKinley, Jay Morrison, Bernie Neenan, Glen Perez, Sandy Ringelstetter, Steve Rosenstock, Karen Sawyer, William Schofield, Chris Siebens, William Smith, Andrew Spahn, Keturah Stephens, Steve Sunderhauf, Rich Tabin, Bill Uhr, Steve Whitley, and Christopher Young.

Finally, the Board of Directors reviewed several drafts and the final report with the understanding that their review did not constitute endorsement either personally or by their organization. Members include: Larry Alexander, Doug Backer, Greg Bullington, Angela Chuang, Ed Cooley, Harry Darnell, Rod Eigenbrod, Mimi Goldberg, Rick Hornby, Bill LeBlanc, Joe Leccese, Rick Leuthauser, James Losleben, Eric Miller, Bernie Neenan, Curt Puckett, Steve Rosenstock, Karen Sawyer, William Smith, and Bill Uhr.

Table of Contents

Executive Summary

The purpose of this policy paper is to recommend principles for use by regulatory authorities and others to encourage the most cost effective use of demand response for energy management. Customer demand response is important to the continued development of wholesale and retail electricity markets. Viable markets are based on the interaction of supply and demand in response to appropriate price signals. Limiting the ability of customers to change their demand in response to prices reduces overall market efficiency, particularly, given the volatility electricity prices.

It is important that regulatory agencies at both the federal and state levels support policies to balance demand response initiatives in step with the increased incentives that open the market to supply-side developers. This balance is needed to provide consumers with appropriate choices and create efficient markets where price volatility is addressed and mitigated, in part, by demand response.

Peak load management or demand response occurs when customers reduce or shift electricity use in response to special programs, including load reduction and time-sensitive pricing. Demand response also occurs when distributed resources come into play for load or economy reasons. The benefits of demand response are many including:

- system reliability,
- cost avoidance,
- system efficiency,
- risk management,
- environmental,
- customer service, and
- market power.

The benefits exceed costs by nearly ten to one according to recent analysis. National benefits of time-sensitive pricing alone could be $15 billion. Demand response resources could contribute over 45,000 MW toward reducing peak electricity demand nationally. The value of demand response is expected to increase over the long term based on expected capacity trends in generation and transmission.

To achieve these benefits, more regulatory encouragement is essential. Principles for regulatory action include:

P1 -- Customer Participation: Demand response markets should be designed to foster participation by customers of all types and sizes.
P2 -- Equal Treatment: Demand response markets should be on an equal footing with generators and all appropriate counterparties.
P3 -- Robust Markets: Encourage numerous participant relationships.

P4 -- Flexible Metering: Metering arrangements between customers and their counterparties should be allowed under mutually acceptable terms.

P5 -- Timely Reconciliation and Settlements: Market operators of demand response have an obligation to provide timely feedback of demand response performance and financial compensation

P6 -- Fair Value: Demand response participants should receive fair value provided in the energy marketplaces.

P7 -- Multiple Program Participation: Customers should be permitted to participate in multiple programs.

P8 -- Agreements for Regulatory Information Only: Customer agreements should be confidential and subject to streamlined regulatory review.

P9 -- Coordinated Regulatory Review and Oversight: Regulatory bodies, which have jurisdiction over demand response programs, must work expeditiously and cooperatively to remove barriers to implementation.

Based on these principles, recommended actions include:

A1 -- Stimulate better reporting on demand response resources.

A2 -- Establish goals for demand response

A3 -- Allow generous cost recovery for demand response.

A4 -- Fully integrate demand response at the outset to provide greater value.

A5 -- Improve standardization of interconnection rules.

A6 -- Encourage examination of environmental rules to foster demand response resources.

A7 -- Creatively phase-out price caps to encourage demand response.

A8 -- Establish rates based on costs including risk management costs.

A9 -- Make decisions on metering timely with fair information ownership.

In summary, demand response offers great potential throughout the country to meet energy needs reliably and efficiently. It is crucial for regulatory officials to enable wholesale and retail markets in ways that afford customers more choices through demand response.

1.0 Introduction and Purpose

The purpose of this policy paper is to recommend principles for use by regulatory authorities and others to encourage the most cost effective use of demand response for energy management. Customer demand response is important to the continued development of wholesale and retail electricity markets. Viable markets are based on the interaction of supply and demand in response to appropriate price signals. Limiting the ability of customers to change their demand in response to prices reduces overall market efficiency, particularly, given the volatility electricity prices.

Barriers to demand response are inherent in the transition to more efficient electric markets and stem from a history of administered pricing in the electric industry which still persists. This history and uncertainties in the development of electric markets discourage investment in the infrastructure that will support appropriate demand response. In fact, it can be argued that the price elasticity of demand has decreased in recent years. Regulated utilities, uncertain about their future role in retail commodity markets, have phased out existing load management programs and deferred investments in metering and information systems that would provide price signals to customers.

As a result, it is important that regulatory agencies at both the federal and state levels support policies to balance demand response initiatives in step with the increased incentives that open the market to supply-side developers. This balance is needed to provide consumers with appropriate choices and create efficient markets where price volatility is addressed and mitigated, in part, by demand response.

This is a long-term proposition. Electricity markets that incorporate economic demand response capability will contribute to the appropriate long-run development of efficient resource investments on both the demand and supply sides.

This paper discusses driving factors that make demand response a necessary component of future electric markets. It identifies points of leverage where regulatory agencies can support economic demand response opportunities. The most appropriate transition path to markets where demand response is a viable option may be uncertain and subject to debate. However, it seems clear that steps need to be taken to move towards this objective. In this context, a set of principles that can be used to guide this effort is offered in this paper.

The Peak Load Management Alliance (PLMA) intends for this paper to be educational and as such to reflect a range of views. The PLMA is a non-profit corporation whose mission is to develop, demonstrate and evaluate methods for reducing peak electrical demand in times of shortness of supply. Membership includes leading companies in electric generation, retail energy services, load aggregation, power exchange, demand response equipment, metering, and information systems.

2.0 Benefits of Demand Response

Peak load management or demand response occurs when customers reduce or shift electricity use in response to special programs designed to induce such energy management. Demand response also occurs when distributed resources come into play for load or economy reasons. Demand response is a natural partner to energy efficiency efforts that seek to reduce overall energy use, not just during critical times.

Programs to acquire or deploy demand response resources are by their nature designed primarily to be time sensitive. They are operated typically as a function of either system load or system costs, although there is often a close correlation between the two. Examples of demand response efforts designed predominately for load management are: direct load control programs, interruptible load programs, and curtailable load programs. Examples of demand response programs designed predominately around time-sensitive economic conditions include: time-of-use rates, real time pricing, coincident peak pricing, and demand bidding or buyback programs.[1] These are discussed more in Appendix A.

Seven categories of benefits from demand response may be distinguished:

- <u>System Reliability</u> **--** Customer demand management can enhance reliability of the electric system by providing negotiated reductions in use during emergency conditions. EPRI has estimated: "Power interruptions and inadequate power quality already cause economic losses to the nation conservatively estimated at more than $100 billion a year."[2]
- <u>Cost Avoidance</u> -- A key driver for demand management is cost avoidance and reduction. This includes direct cost savings from avoided generation as well as avoided transmission and distribution costs including capacity costs, line losses and congestion charges. Indirect cost avoidance occurs through reductions in wholesale market prices, which customers may never see. An EPRI study concluded that "… a 2.5% reduction in electricity demand statewide could reduce wholesale spot prices in California by as much as 24%; a 10% reduction in demand might slash wholesale price spikes by half."[3]
- <u>System Efficiency</u> -- When customers receive price signals and incentives, usage becomes more aligned with costs. To the extent customers alter behavior and reduce or shift on-peak usage and costs to off-peak periods, the result is more efficient use of the electric system.
- <u>Risk Management</u> -- Providers of retail energy compete for power in wholesale markets where prices can vary dramatically from day to day, and hour to hour. Price guarantees have substantial value to certain customers, and efficient markets are characterized, in part, by the ability to provide risk management products using all available economic tools. Retailers can hedge price risks by creating callable quantity options (i.e., contracts for demand response) and by creating appropriate price offers for those customers who are willing to face varying prices. In this manner, risk management products can be most economically offered to those customers that most benefit from them. Demand response helps manage risks through ready

---

[1] EPRI, "The Western States Power Crisis: Imperatives and Opportunities," June 25, 2001., p. 23, www.epri.com.
[2] EPRI, "Technology Action Plan Addresses Western Power Crisis," <u>EPRI Journal, Summer, 2001., p. 5.</u>
[3] Taylor Moore, "Energizing Customer Demand Response in California," <u>EPRI Journal</u>, Summer, 2001, p. 8.

availability, high reliability, refined modularity and rapid dispatchability. Risks are reduced all along the value chain.

- Environmental – Demand response can reduce environmental burdens placed in the air, land and water. Electricity generation is responsible for consuming one billion tons of coal annually and accounted for 90% of U.S. coal consumption in 2000.[4] For natural gas, utility power plants consumed an estimated 3.1 quads or 13% of national natural gas usage in 2000.[5] Demand response can also reduce or defer new plant development, and transmission and distribution capacity enhancements resulting in land use benefits for neighborhoods and countrysides.
- Customer Service -- Many customers welcome opportunities to manage loads as a way to save on energy bills and for other reasons such as improving the environment. In this the age of choice, demand response provides customers with choice in how they use electricity.
- Market Power -- Demand response programs help mitigate market power of traditional and new energy suppliers by greater customer choice and participation.

---

[4] U.S. Department of Energy, Energy Information Administration, Monthly Energy Review, December, 2001, p. 88.
[5] American Gas Association, "Balancing America's Energy Needs," American Gas, October, 2001.

Note: It has been suggested Sections 3 through 6 be placed as individual appendices. The reason is to move principles and actions sections to the forefront. On the other hand, the executive summary highlights principles and actions at the beginning of the policy paper.

3.0 Assessing the Economic Value of Demand Response

It is important not only to recognize the many benefits of demand response but to quantify them. This section confirms the benefits are large and well exceed the costs.

3.1 Benefits are Many Times the Costs for Demand Response for NYISO

Three types of benefits may be distinguished from reducing demand in response to program requests:

- savings from reduced market prices,
- savings in costs of hedging due to reduced price volatility, and
- end-use customer savings in costs of outages.

The high value is demonstrated in a timely analysis of the demand response programs of the New York Independent System Operator (NYISO).[6] The analysis shows benefits are many times over.

During the summer of 2001, some 292 customers participated in the Emergency Demand Response Program (EDRP) offered by the NYISO. Participants agreed to reduce loads upon a two hour advance notice from the NYISO. Some 72% of the customers participated through their load serving entity (LSE), while 25% took advantage of offers from Curtailment Service Providers (CSP) and 3% contracted directly with the NYISO.[7] Participants provided a maximum reduction of 425 MW. Program payments totaled $4.2 million for four event days.[8]

One set of benefits is achieved with reductions in market prices associated with activating the demand response programs. An analysis of location-based marginal pricing (LBMP) across five zones produces collateral benefits of $13 million for the four event days.[9]

A second benefit of the program is improved reliability. Customers gain through reduced outage costs. "Outage costs reflect the inconvenience associated with rescheduling activities, and damages suffered as a consequence of service curtailment."[10] "Given that the generally accepted value for outage costs is in the range of $2,500 – 5,000/MWH, the benefit cost/ratio is between 4.8 to one and 9.5 to one."[11] This is based on payments of $4.2 million.

[6] Neenan Associates, "NYISO PRL Program Evaluation: Executive Summary," New York Independent System Operator, January 15, 2002.
[7] Ibid., p. E-4.
[8] Idid., p. E-29.
[9] Ibid., p. E-13.
[10] Ibid., p. E-9.
[11] Ibid., p. E-9.

"While it is tempting to compare collateral benefits with the payments to Participants in order to construct a benefit/cost test, such comparison is not appropriate. The collateral benefits reflect transfers from generators to LSEs and possibly eventually to retail customers, to overall improvement in welfare."[12]

A third type of benefit is achieved by damping the variability in prices. There are substantial benefits in terms of reducing prices paid by LSEs to hedge their obligations, either through physical bilateral supply contracts or financial hedges. The estimate for the four load reductions in August, 2001 alone totals $3.9 million.[13]

The foregoing costs and benefits have been calculated for the emergency program with two hours notice. The NYISO offers a second demand response program. The day-ahead demand response program (DADRP) allows participants to bid in proposed load reductions. During the summer of 2001, some 16 participants offered 134 MW of load and provided a maximum of 25 MW. Payments totaled over $200,000. Collateral benefits were estimated at $1.5 million and benefits in reduced hedging costs of $700,000.[14]

Customers are allowed to participate in either or both programs. Although loads offset by backup generators are only allowed to participate in the emergency program, if diesel fueled. Gas fired units may participate in both emergency and day-ahead programs.[15] Customer research showed general satisfaction with both programs, although participants prefer longer notification periods and higher payments. "This underscores the fact that in program design, there are substantial tradeoffs between those features of value to the market and those of value to customers."[16]

LSEs also reported satisfaction with the NYISO programs. But they noted past practices in offering demand response programs to their customers and a preference over the NYISO standard offer. This was because "…some felt that there was a bias toward wholesale interests that compromised retail interests and led to programs that were overly complicated and not attractive to retail customers."[17]

In summary, recent empirical research demonstrates demand response programs offer benefits many times their costs. Furthermore, benefits should increase as experience grows among existing and prospective participants.

3.2 Benefits Could Have Saved $2.5 Billion in California in 2000

One type of demand response program relies on dynamic pricing with hour-to-hour variations. Hourly retail pricing tied to hourly wholesale costs provides customers with opportunities to save

[12] Ibid., footnote 13, p. E-13
[13] Ibid., p. E-14.
[14] Ibid., p. E-29.
[15] Ibid., p. E-2.
[16] Ibid., p. E-26.
[17] Ibid., pp. E-26-27.

in two ways. First, customers avoid the risk management costs included in traditional tariffs. Second, consumers can modify usage in response to hourly prices to further reduce costs.

Traditional utility tariffs have been characterized by Dr. Eric Hirst as encompassing two components: a) the electricity commodity and b) the risk management or insurance component.[18] Historically, utilities and regulators factored in the insurance aspects implicitly, by allowing generation capacity reserve margins to meet load fluctuations. Higher tariffs were permitted to allow for higher costs associated with meeting peak loads due to fluctuations in economic activity, human behavior, weather and other factors. In deregulated markets, such vertical bundling of commodity and risk management is difficult to sustain. With wholesale and retail competition, price fluctuations have increased causing greater risks that standard tariffs will not cover costs.

Dynamic hourly pricing allows customers to pay less, in part, since the risk or insurance costs are not included. The benefits of hourly pricing can be substantial as has been calculated for California. If hourly pricing had been in place for 20% of the retail load with an overall price elasticity of -0.25, electric bill savings would have been $220 million in California for 1999.[19]

Savings would have been even greater for 2000, since prices in California were not only almost four times higher but also much more volatile than in 1999. Dynamic hourly pricing would have saved consumers about $2.5 billion in 2000, or 12% of the statewide power bill. “The benefits of dynamic pricing increase rapidly with price volatility.”[20]

While savings may not be as much in normal years, during abnormal years with high fuel prices, capacity shortages, and rapid load growth, dynamic pricing programs more than pay for themselves, like insurance. “Implementing price-responsive demand programs requires policy makers to understand and accept the insurance aspects of dynamic pricing.”[21]

3.3 Benefits Nationally Could be $15 Billion per Year

Dynamic pricing could save from $10 billion to $15 billion per year according to estimates of McKinsey & Company.[22] The estimate assumes dynamic pricing would be applied to all types of customers including residential, commercial and industrial facilities. Based on experience with these programs, it is assumed that users on average would shift five to eight percent of their load from peak periods and curtail use another four to seven percent.[23]

About 20% of the savings are attributed to such changes in usage. About 80% of the savings are attributed to lower wholesale peak prices.[24]

---

[18] Eric Hirts, “The Financial and Physical Insurance Benefits of Price-Responsive Demand,” January, 2002, p.1.
[19] Ibid., p. 4.
[20] Ibid., p. 5.
[21] Ibid., p. 9.
[22] McKinsey and Company, “The Benefits of Demand-Side Management and Dynamic Pricing Programs,” May 1, 2001, p. 2.
[23] Ibid. p. 4.
[24] Ibid., p. 5.

McKinsey translates the savings into other benefits including avoiding:

- $16 billion in peaking plants,
- 250 peaking plants at 125 MW each,
- 31,000 MW of peaking capacity,
- 680 billion cubic feet of natural gas, and
- 31,000 tons of nitrous oxide pollution per year.[25]

[25] Ibid., p. 7.

4.0 Market Opportunities and Challenges

The opportunities for demand response are large and largely untapped. This section addresses key opportunities for and challenges to encouraging more demand response efforts.

4.1 Demand Response Opportunity of 45,000 MW

EPRI has estimated that demand response programs could reduce peak demand in the U.S. by 45,000 MW or about 6% of peak baseline usage. They estimate program costs of $4.2 billion per year.[26]

Yet, the market for demand response resources has barely been tapped. Facilities with computerized energy management systems have capabilities to manage lighting, air conditioning, and other energy uses. Production lines, agricultural processes, mining operations and other industrial applications can be shifted or reduced during peak periods.

Distributed resources serve a demand response role in many applications. For example, backup generators serving commercial and industrial facilities are estimated to have about 80,000 MW of capacity. While it is not necessary for the units to be synchronized with the grid, the large majority of this capability is not networked for parallel applications in demand response programs. Also the large majority is diesel fuel fired as opposed to cleaner natural gas fired generation.[27]

Utility Interest in Demand Response

Only about 25,000 MW of load, including backup generation, signed up for demand management programs in 1998 according to estimates by Edison Electric Institute based on U.S. Department of Energy surveys. About ½ of the load came from industrial customers, ¼ from commercial and ¼ from residential. While over 25,000 MW was available for demand management, only about 50% was called upon during 1998.[28]

Utilities have recently shown an increased interest in demand response. A national survey of utility managers in 2001[29] showed the top three reasons for load management were to:

- reduce system peaks,
- reduce high-cost energy, and
- provide economic advantage for utility.

[26] EPRI, "The Western States Power Crisis: Imperatives and Opportunities," June 25, 2001, p. 24/
[27] Leland Keller, E source, "Distributed Generation Aggregation, Dispatch and Control," 3rd Annual International Symposium on Distributed Energy Resources, November 2, 2001.
[28] Steve Rosenstock, "The Future of Load Management," Edison Electric Institute, October, 2000.
[29] Charles Newton, "From DSM to Demand Response," Electric Perspectives, November/December, 2001, pp. 36-37.

<u>Table 1</u>
Survey of Load Management Objectives
Ratings from 5 (most important) to 1 (least important)

Objective	Rating
Reduce system peaks	4.55
Reduce high-cost energy	4.23
Economic advantage for utility	3.78
Savings to consumer	3.55
Maintain customer comfort	3.42
Reduce capacity constraints	3.37
Do load shifting	3.20
Do our part to maintain system stability	3.18
Use for operation considerations	2.95
Reduce reserve requirements	2.95
Improve utility's system-wide efficiency	2.91

Notably, the bottom three reasons in 2001, were the top reasons in a similar survey four years earlier. In 1997, utility managers professed a lack of interest in demand management programs because:

- measures are not cost-effective,
- no incentive from wholesale rate structures, and
- excess capacity.

<u>Capacity Drivers for Demand Response</u>

Generating capacity reserve margins have dropped nationally from 57% in 1993 to 8% in 2001. This has helped stimulate interest in demand response resources along with improved cost-effectiveness.[30]

Generation reserve margins are expected to improve in some reliability regions but not in others. Even where margins may increase, demand response should be sought as a stabilizing resource to help mitigate the potential for boom and bust cycles that are possible in commodity markets such as electricity generation.

(Note: The following table is partially complete, but will be finished in few more days.)

Table 2 presents a comparison of the forecasted reserve margins in 2002 and 2005 for each NERC region between data filed with NERC (Regional Assessment) and e-Acumen's forecast (e-Acumen Assessment). Forecasted reserve margins for the Regional Assessment are derived per the net supply and demand information provided in the NERC Electricity Supply and Demand Software, April 1, 2001[31] (2001 ES&D). The e-Acumen forecast of reserve margins is derived using forecasted load for the 2001 ES&D and e-Acumen's base case capacity

[30] Ibid.

	Table 2 **Reserve Margin Forecasts**	
	2002	**2005**
ECAR		
Regional Assessment[1]	14%	11%
e-Acumen Assessment[2]		
ERCOT		
Regional Assessment[1]	40%	35%
e-Acumen Assessment[2]		
FRCC		
Regional Assessment[1]	20%	23%
e-Acumen Assessment[2]		
MAAC		
Regional Assessment[1]	26%	52%
e-Acumen Assessment[2]	22%	25%
MAIN		
Regional Assessment[1]	29%	27%
e-Acumen Assessment[2]	24%	27%
MAPP		
Regional Assessment[1]	20%	15%
e-Acumen Assessment[2]		
New England		
Regional Assessment[1]	33%	26%
e-Acumen Assessment[2]	38%	36%
New York		
Regional Assessment[1]	17%	31%
e-Acumen Assessment[2]		
SERC		
Regional Assessment[1]	13%	15%
e-Acumen Assessment[2]	23%	33%
SPP		
Regional Assessment[1]	17%	13%
e-Acumen Assessment[2]		
WSCC		
Regional Assessment[1]	25%	46%
e-Acumen Assessment[2]		

[1] Based on 2001 NERC ES&D. New York based on the 2001 Load and Capability Report.
[2] Based on e-Acumen's Powerview™.

assessment. It is based on Powerview™[32], a database that tracks the status of every power plant currently under development in the United States, in order to assess an appropriate view of new capacity additions, or merchant plant activity.

[31] New York forecast based on net supply and demand information provided in the 2001 Load and Capability Report.
[32] Powerview™ is a proprietary e-Acumen product. Please contact 1-877-769-3740 for more information.

Transmission capacity limitations are another driver for using demand response resources. Transmission congestion is growing more prevalent. Costs of transmission congestion have been calculated as exceeding $800 million and this is just for New England, New York, PJM and California alone and just for 2000.[33]

The transmission situation is forecast to deteriorate further. Normalized transmission capacity is expected to decline from 201 to 176 MW-miles/MW demand between 1999 and 2009.[34] "Maintaining a normalized capacity of 201 MW-miles/MW demand throughout the decade requires the construction of 26,600 GW-miles, compared with planned construction of only 6,200 GW-miles."[35] If instead of declining, construction maintained current levels of transmission capacity, investments would total an estimated $56 billion. This is equal to the current book value of transmission assets and about half of the $105 billion investment forecast for new generation capacity over the ten year period.[36]

Clearly, demand response resources are a necessary and valuable resource in the energy future to complement trends in both generation capacity and electricity transmission and distribution.

4.2 Market Challenges

Numerous challenges in both retail and wholesale markets frustrate the use of demand response resources.

Retail Market Challenges

The economic value created by demand response that is not captured in market prices is a compelling argument for the continued development of demand response programs and infrastructure even if there is a boom in plant capacity. Because demand response is not captured sufficiently in market prices, there is significant underinvestment, similar to past practices with energy efficiency investments.

The challenges to demand response appear in multiple ways. Barriers in retail markets may be classified as "…lack of information, lack of incentives, lack of enabling technologies, lack of functional wholesale market, lack of customer choice."[37]

It is a challenge to recruit both new and existing customers. For new customers in particular, demand-side resources require time to develop and consistency in application, if the long-term benefits are to be attained.[38]

---

[33] Eric Hirst and Brendan Kirby, "Transmission Planning for a Restructuring U.S. Electric Industry," Edison Electric Institute, June 2001. p. 8. Citing R. Gales, J. Graves, and J. Clapp, *The Future of Electric Transmission in the United States: A Vision for Transmission as a Vibrant, Stand-Alone, For-Profit Business*, PA Consulting Group, January 2001.
[34] Hirst and Kirby, p. 8.
[35] Ibid.
[36] Ibid., p. 9 – 10.
[37] EPRI., "The Western States Power Crisis: Imperatives and Opportunities," June 25, 2001, p. 29.
[38] Based on correspondence with Joel Gilbert, January, 2002.

For existing customers, the transition to retail competition presents maddening challenges for customers committed to demand response. Texas had over 3,000 MW involved in demand response programs prior to retail choice. These resources appear to have been lost in the transition to retail choice. The load serving entities (LSEs), also known as retail energy providers (REPs), neither have picked up or been encouraged to operate the demand response programs.[39] One reason is that the regulatory rules are limiting: "Savings through load management programs, including interruptible rates, may not exceed 15% of the utility's total demand reduction goal."[40]

Part of the difficulty is that distribution revenues are tied typically to throughput. This acts as a disincentive to demand response programs where less energy is sold, unless a non-bypassable surcharge is levied on the distribution of electricity.[41]

A further challenge at the distribution level is handling load disparities. Distribution systems may not peak at the same time as transmission systems. Congestion charges at the transmission level have proven effective at the transmission level. However at the distribution level, congestion charges are more difficult to implement.

Demand response programs including distributed generation can be effective in addressing local load situations. However, it is a difficult to design market pricing formulas to address these opportunities. In practice, demand response resources may be called upon to meet regional system needs when local distribution conditions are quite adequate.

Wholesale Market Challenges

An organizational challenge for wholesale markets is that there is too much fragmentation among jurisdictions. It has been suggested there is a need to move wholesale markets to a regional level which will require cooperation among multiple jurisdictions.[42]

A specific challenge posed in existing wholesale markets is the use of price caps to reduce market volatility. For example, the FERC price cap in the WSCC reduces demand response interest and participation potential. If retained as its unreasonably low level of $100/MWH, it may leave lasting damage to the energy markets in that region. Many load serving energy participants either see no reason to expand or in some cases even maintain their demand response capabilities.

Mandating prices around $100/ MWH might possibly be appropriate in monthly block forward markets, but should certainly not be in place for day ahead or shorter term markets. At the moment, the WSCC cap is being applied to the day ahead price for all sixteen (16) hours of the on peak period. That low price applied to individual hours kills virtually all customer demand response activity.[43]

---

[39] Ibid.
[40] Public Utility Commission of Texas, "Substantive Rules," 25.181 (g)(2)(I).
[41] EPRI., "The Western States Power Crisis: Imperatives and Opportunities," June 25, 2001, p. 30.
[42] Ibid., p. 28.
[43] Communications with Joel Gilbert, January 20, 2002.

Such low prices present a challenge to justifying demand response programs. As it is, demand response programs are subject to heavy analysis before and after implementation to confirm their cost-effectiveness. Some observers note that much larger sums are spent on creating and operating ISOs with comparatively little debate or analysis. Thus in terms of organizational planning and program development, more encouragement is warranted for demand response.

Another need is for better system planning. In the absence of more systematic planning, market participants are at greater risk, including generators, distributors, retailers and customers. Assuming ISOs are encouraged to take the lead in more comprehensive system planning, there are challenges in establishing baselines for information needs among market participants and in developing acceptable forecasting methods.[44]

[44] Ibid., p. 30.

5.0 Fundamentals of Demand Response

The most fundamental proposition for any product is that there must be a buyer and a seller. The question of who is the buyer or customer and who is the provider or seller can be quite confusing with demand response.

In the case of energy, the ultimate buyer is normally the end-use customer, whether a residence, business, farm or factory. In the case of demand response, the situation can be reversed. The energy end-user may be selling callable demand reductions to another party, i.e., the power supplier might usefully be viewed as the buyer of demand response options.

The value chain between the energy producer and energy user can be quite complex. This is especially true in retail choice markets with unbundled electricity products as compared to monopoly markets with vertically bundled products.

To better understand the market structure it is helpful to characterize the market participants.

- An end-use customer consumes energy and its services.
- A load serving entity (LSE) buys or acquires power and sells to an end-use customer. In some jurisdictions, these are referred as an energy service provider (ESP), a retail energy or electric provider (REP), or simply a utility.
- A marketer recruits customers and acts as a LSE since it takes ownership of the energy.
- An aggregator recruits customers and turns them over to a LSE without taking ownership of the energy.
- A curtailment service provider (CSP) recruits customers for demand response resources explicitly and in effect provides power to the market.
- An independent system operator (ISO) manages the electric transmission system to insure a balance between the demand and supply of energy, including demand response resources.
- A regional transmission organization (RTO) owns electric transmission systems. It may also be an ISO.
- A generator sells power to a LSE to meet customer needs and to the ISO to meet system needs.
- A power exchange (PX) allows buyers and sellers of power to affect transactions including for demand response resources. An ISO may also serve as a PX.
- A utility distribution company (UDC) delivers power from the RTO to the end-use customer. In some jurisdictions, these entities are called a local distribution company (LDC).
- A utility combines many of these roles in retail markets. A utility in monopoly markets with vertical integration serves as the generator, LSE, UDC and CSP.
- A scheduling coordinator fulfills transactions and settlements between contracting parties for size in megawatts, start and end times, beginning and ending ramp times and other aspects involving the receipt and delivery of power.

- A meter service provider installs and maintains energy metering equipment.
- A meter data management agent reads and verifies meter information.

Now that key market participants have been defined, it is useful to characterize the market functions.

5.1 Demand Response as a Product Offering

One way to view the structure for a demand response market is in textbook formula of the marketing mix.[45] There are, in most markets, five "Ps" to the marketing mix:

- Product: features, quality specifications, operations, services
- Price: rates, payments, discounts, incentives, financing
- Place: delivery, channels, installation, inventory
- Promotion: information, education, advertising, sales
- Public policy: rules, regulations, reporting

Demand Response Product

Academics classify products as durable goods, nondurable goods and services.[46] The demand response product or service may be defined in quantitative terms such as the amount of energy provided, quality of energy provided, amount of energy reduction, and amount of capacity made available for reduction. Additional characteristics of demand response products may include time of use, time of day ahead or prospective use, timing of load reduction notification, timing of load reduction event, duration, frequency and some combination of these characteristics. Such measures may be fixed or variable and mandatory or discretionary depending on the program.

The product may also be defined in terms of types of actions taken, types of technologies involved, types of measurement employed, and some combination of these factors. Usually an agreement or contract is necessary to define the terms and conditions for the demand response product, including pricing and delivery provisions.

Demand Response Pricing

Some prices are part and parcel of the product offering such as time-of-use rates, real-time pricing and coincident peak pricing. In these cases, the product is electricity defined by amount and time of use within specific pricing structures. The customer is the buyer.

In the case of interruptible load programs, curtailable load programs and direct load control programs the pricing takes the form of credits, discounts, and other forms of direct or indirect payments. Here the customer is the seller receiving payment from the buyer.

---

[45] Philip Kotler, Marketing Management, Prentice-Hall, Inc., 1984, p. 69.
[46] Ibid., p. 465.

In the case of demand bidding or buyback programs, there is a need for different pricing mechanism and a liquidity point. A liquidity point is where the value to the owner of the demand resource or the end-use customer is determined. Liquidity points can be established with an independent system operator (ISO) or in bilateral energy markets. Prices are set based upon the perception of value and risks. These usually are based on the buyer's perception of avoided or actual incremental costs, time periods, load reductions and duration of demand response programs.

Another aspect is the pricing of transmission and distribution or wires services in a manner that better represents the long-term cost of adding or upgrading capacity. Rather than uniform pricing, separate pricing for both commodity and wires portions could better reflect their different marginal costs. Then demand response programs and time-sensitive pricing incorporating these higher incremental prices can enable shorter paybacks for investments in load management technologies. Depending on the market and the class of customer, the wires component can represent between 20% and 50% of the total energy bill.[47]

To take maximum advantage of demand response and time sensitive pricing, investments will be needed in distributed resources and in information, controlling, metering, and communication technologies. In the absence of time sensitive prices, less investment is likely to occur.[48]

Demand Response Delivery

Another fundamental function in the mix is how the product is placed or delivered. The end-use customer may deliver the demand resource directly to the ultimate buyer, namely the independent system operator or ISO. Or, the end-use customer may deliver through one or more market intermediaries, such as the LSE or the CSP. Thus the delivery channel may be from the end-use customer to a curtailment aggregator and then to the market operator or ISO. All parties want assurance that what was sold is paid for according to appropriate terms and in a timely manner.

A key aspect is the ability for timely and uncontested measurement and verification. In some cases, the details of a program are stipulated or understood as part of prepaid incentives to customers (such as common in residential air conditioning or water heating load control products). In other cases, program designs allowing easy customer participation and simple protocols for performance measurement and verification are the key enabling (or disabling) mechanisms in a demand response.

Demand Response Marketing and Promotion

The roles for traditional, vertically integrated energy companies are in transition. In many cases, the "wires company" is no longer permitted to market and promote demand response. The grand plan was that innovation in the market would fill this need. That has not yet materialized. As a result, today's customers may not be aware of the benefits that they attain through exercising their ability to adjust use to better match the profile of electric prices. This may require external

[47] Correspondence with Bill Urh, December, 2001.
[48] Correspondence with Bill Uhr, December, 2001.

agents to fill the void (such as the ISO or RTO) to operate demand response programs. But even here, the need for information, marketing, and technical assistance to customer is a daunting task.

Thus, marketing and promotion is an important function in the transition to open, competitive markets. There are multiple value propositions just as there are multiple demand response opportunities and market participants. For demand response to succeed, the many market participants must be educated and indeed sold on the values that can be achieved.

Success in marketing is not only related to education and awareness of participants, but also program stability. If program designs change radically from year to year or even within a year, it is more difficult to attract and retain end-use customers as well as others in the value chain.

Demand Response Public Policy

Government rules and regulations play a larger role in most products than is generally recognized. Whether producing consumer goods or services, from apples to zinc, market success can be depend heavily upon compliance with government policies such as on health, safety, environment, anti-trust, insurance and energy of course. Since this paper is oriented toward public policy for demand response, this fundamental function for success is central. Thus, part of the education or marketing function should extend to regulatory officials in energy, environmental and other agencies.

5.2 ISO Economic Demand Response Programs

FERC has actively encouraged ISOs to offer demand response and distributed resource programs.[49] In response, several ISO programs were offered in the summer of 2001. A summary of the California, New England, New York and PJM programs is shown in Table 3.[50]

[49] Reference FERC Order of May 18, 2000.
[50] Summarized from Donald Gilligan, "Grading 2001's ISO Demand Response Programs, Energy User News, November, 2001. With refinements from Glen Perez, CAISO. PJM additions and other modifications from Steve Fernands, Price Responsive Load Coalition.

TABLE 3
ISO Offered Economic Demand Response Programs in 2001

Subject	CA ISO -DRP	NE ISO Price Resp.	PJM	NY ISO Day Ahead
Period	Jun 1 – Sep 30, 2001; Oct. optional; 11 am – 7 pm wkdys	Jun 1 – May 31, 2002 7 am – 11 pm wkdys	June 1 – May 31, 2001 Any time, any day	2001- Oct 31, 2003 Any time, any day
Eligible participant	Aggregator of end use customer	NEPOOL member for end use customer	CSP or LSE	CSP or LSE
Eligible load	1 MW +	100- 500 kW	100 kW +	1 MW +
Call criteria	Resource shortage	Price $100/MW+	Participant is a price taker	Participant bids
Response period	35 minutes	Variable per notification	Participant sends e-mail	Defined in customer bid for Day Ahead Market
Respondent option	Mandatory; up to 24 hours per month	Optional	Voluntary	Mandatory if accepted DA
Duration	4 hours blocks	Variable	Variable	Variable
Compensation	Reserved demand + energy	Based on hourly energy clearing price	Real Time Location Marginal Price(LMP)	Day Ahead Location Based Marginal Price (LBMP)
Baseline criteria	10 highest out of 11 prior workdays	10 prior wkdys with adjustments	Hour Before	5 highest of 10 prior days
Performance measure	% of reserve achieved	Baseline difference	Baseline difference	Baseline difference
Payment channel	Scheduling controller, aggregator, customer	NEPOOL participant, customer	LSE/CSP, end-use customer	LSE/CSP, end-use customer
Metering method	Interval meter	Interval meter, phone line, PC	Interval meter	Interval meter
Notification method	Email or epage to schedule coord., aggregator, end user	Internet based communication system (IBCS)	Customer e-mails PJM before or during curtailment	Day Ahead notification over internet
Software requirement	Up to aggregator.	IBCS	Internet	Internet to ISO
Program fees	None	Negotiated + costs for hardware/software	None	None
Emergency Program	Offered	Offered	Offered	Offered

Each of these ISO programs differed in important respects. The California program offered upfront capacity payments which presented minimum payments that are paid even if the program is never called. This guarantee helped customers make investments in equipment necessary to participant in the demand response programs. Payment channels also varied across programs.

In addition to these programs, others were offered through the ISOs. CAISO offered a discretionary load control program (DLCP) with day ahead notification versus 35 minutes, acceptable optional metering versus mandatory interval metering, and compensation for energy but not capacity, as well as other differences.[51]

[51] Communication with Glen Perez, California Independent System Operator, January, 2002.

6.0 The Role of Time-Based Measurement of Electric Use

The ultimate market solution may be time-based measurement of electricity consumption for each customer. However, this is not practical in the near term. Most applications of demand response require enhanced metering and measurement for success. Proper measurement policies will enable time-sensitive pricing which in turn encourages metering investments.

6.1 Measurement Enables Pricing

A growing number of industry stakeholders believe that a fundamental requirement of an efficient electric power industry is the widespread availability of time sensitive measurement of customer usage. This argues for accelerating the implementation of time sensitive pricing mechanisms at the retail level through policies that promote increased metering of time-based electric use. This would not just be for large commercial and industrial customers but, over time, could include all customers as the costs for this capability continue to decrease.

Another operational motivation for time-based measurement is to move away from dependence on generic load profiles, commonly referred to as load profiling, for end-use customer segments. Generic load profiles mask differences between customers and provide little incentive for LSEs, UDCs or end-use customers to better manage their energy consumption. They also enable gaming to the detriment of a true open market.

6.2 Pricing Enables Investments

Once the enabling infrastructure is in place, the most significant benefit from time-sensitive measurement and pricing is likely to be the innovation in products and services designed to help customers economically manage their energy. To the extent that regulators imposed fixed-price rates (in part because the metering methods fail to enable a better mechanism), the incentive to develop and offer innovative products and services is extinguished.

McKinsey has estimated the cost of implanting "…the platform needed for dynamic pricing will create business opportunities worth from $25 billion to $30 billion."[52] Utilities are reluctant to invest in technology in part because of uncertain allowance for cost recover by regulatory commissions. "A utility must therefore receive some assurance from regulators that it will be able to recoup these costs and make a return on the investment."[53]

One approach is to encourage ISOs to factor in the costs of advanced metering undertaken by utility distribution companies, load serving entities and even end-use customers. While the ISO may not have direct jurisdiction over such regulated or unregulated entities, cost sharing arrangements and reviews of demand response activity would help. As has been seen in the program evaluation for the NYISO and for other programs, the savings from demand response

[52] Justin A. Colledge and Jason Hicks, James B. Robb, and Dilip Wagle, "Power by the Minute," *The McKinsey Quarterly*, Number 1, 2002, p. 2. www.mckinseyquarterly.com.
[53] Ibid.

programs are substantial. Certainly, they are sufficient to underwrite some if not all the costs of metering.

Such programs can be mandatory or voluntary. Mandatory programs have the advantage of engaging more participants and achieving higher net benefits. Voluntary programs risk having low participation and engaging too many free riders.[54]

6.3 Settlement and Reconciliation

Time-based measurement allows quicker settlement. Typically time-based metering is associated with better communication systems including more frequent data collection. Furthermore, the data can be communicated to more entities where permitted. This facilitates quicker settlement when data does not have to be passed through a series of agents.

Reconciliation offers an opportunity to correct problems with early settlement. In the event that mistakes occur in recording, reading or translating data for billing and settlement purposes, the differences can always be reconciled at a later date. Then, rather than hold settlement hostage until all analysis or comparisons are done, market participants can proceed with full payments. Marginal adjustments need not delay full payments since the adjustments can be reconciled at a mutually convenient time for the parties involved.

Note: It has been suggested that 6.3 be deleted.

[54] Charles River Associates: "TOU Pricing for Mass Markets," 2002.

7.0 Regulatory Principles for Demand Response

This section presents regulatory principles to stimulate greater use of economic demand response resources. The organizing principles presented below provide a basis for judging demand response programs, including load management and dynamic pricing designs.

P1 -- Customer Participation: Demand response markets should be designed to foster participation by customers of all types and sizes.

Most electricity customers are not energy professionals and are unfamiliar with the details of how supply side energy markets work. They also vary considerably in their ability to be price responsive. Some are eager and willing to agree to mandatory or involuntary participation while others may only be comfortable with voluntary agreements. Some will have automation and direct load control capability while others will rely on manual procedures. Each of these attributes will be factored into the value of customer demand response the buyer is willing to offer.

P2 -- Equal Treatment: Demand response markets should be on an equal footing with generators and all appropriate counterparties.

Demand response resources of equivalent size and availability to generation resources should be afforded equal treatment, as a minimum, and in transition should be considered for preferential treatment. Demand response resources bring many, if not more, of the virtues attributed to some generation resources including dispatchability, reliability, and flexibility.

P3 -- Robust Markets: Encourage numerous participant relationships.

Market efficiency is achieved when buyers and sellers can easily find each other and come to agreement. Currently, demand response is often captive to the load serving entity which may have little-to-no financial incentive to "trade" this resource into regional markets. Since LSEs often set prices based on expected volumes, they may resist marketing the demand response concept to captive customers. Others, including other LSEs, may wish to acquire the resource and permit the customer's LSE a portion of the resulting benefits for the channel access, metering information, and aggregation value. In addition, it is likely that several parties may wish to acquire this resource and may have varying views about value and performance. Under this scenario, it is likely that the customer would see multiple offers for demand response depending upon their willingness to accept liquidated damages or have real time metering. These details are all part of creating an open, competitive and efficient market and should be encouraged.

P4 -- Flexible Metering: Metering arrangements between customers and their counterparties should be allowed under mutually acceptable terms.

Acquiring demand response resources and performance information may require a supplemental investment in either an existing metering upgrade or change, or in the communication to or reading of that meter. The seller or the buyer of that resource should be permitted to reach mutually acceptable terms for compensation.

The metering information necessary to employ demand response effectively into regional energy markets varies with the counterparty perspective and the type of resource. These are private treaty agreements that are integrally tied to the price paid for the resource. No one standard of commerce is necessary. In fact, it may be acceptable to even use aggregate substation, feeder and lateral metering, in lieu of individual customer metering (as in the case of using radio-controlled residential switches).

P5 -- Timely Reconciliation and Settlements: Market operators of demand response have an obligation to provide timely feedback of demand response performance and financial compensation

Effective demand response programs require active end use customer participation. Most of these customers are not in the electricity business but are changing their business practices or processes to participate in demand response programs. Timely feedback to customers of demand response performance and financial compensation is key to the long success demand response programs. Where possible feedback on performance and compensation should occur on a next day after the event with settlements completed no later than 60 days after the event.

From a demand response provider perspective, receiving direct payments for the curtailed capacity is a critical component. Payments that must pass through a third party, whether a scheduling coordinator in California or the customers load serving entity (LSE), clearly discourages participation. Some scheduling coordinators may serve multiple LSEs or CSPs and take a share of the payments, even though they added not value to the process.

P6 -- Fair Value: Demand response participants should receive fair value provided in the energy marketplaces.

The final value for demand response will depend upon the regional markets along with any location specific attributes. Some may consider these regional markets on a capacity basis while others may seek energy only resources. In all cases, it is likely that demand response will reduce losses, transmission congestion, and thereby improves reliability. The value for these improvements may be additive and actually exceed the value supply-side resources, especially where demand response is effectively already delivered and net of losses. This higher value is perhaps most compelling when demand response reduces the final clearing price in a congested spot market.

P7 -- Multiple Program Participation: Customers should be permitted to participate in multiple programs.

Some facilities may be able to participate in emergency programs with short notice as well as buy-back programs with longer notice. Certain customers are only able to respond to reliability needs in emergency situations and may even do so with no need for compensation. Most, however, will want some fixed payment for their willingness to curtail or interrupt operations. Others may prefer to be offered a price for a given time period and decide whether to participate. And still others may even be willing to bid in a price they are willing to accept for such actions.

There is a distinct possibility that emergency reliability needs do not coincide with market prices. Experience in the Southeast indicates that high market prices occur less than 30% of the time during which the Southeast was a critical peak load condition.[55] That is, more than two-thirds of the time, there would be no reason for an energy company in the Southeast to offer their customers a price signal based upon local supply conditions.

Therefore, emergency payment programs neither should forbid participation in an economic program nor encourage gaming. Similarly, customers with demand response resources should be permitted to participate in both capacity and energy markets, where these exist, just as with generators.

P8 -- Agreements for Regulatory Information Only: Customer agreements should be confidential and subject to streamlined regulatory review.

Agreements for demand response between market participants often take into account numerous factors not easily subject to regulatory standardization. Payment terms alone can have multiple variations in levels, structures, and timing of both incentives and penalties. Other factors subject to negotiation include notification, operations, measurement, and reporting. For large accounts, bilateral transactions can be complicated and time consuming to negotiate. Furthermore, once agreements are reached, time may be of the essence to achieve reliable demand response. Regulatory guidance should allow these agreements as much latitude as possible. If anything, regulatory responsibilities should be limited to post hoc review and analysis.

Agreements are often so unique that comparisons become difficult without careful analysis. Exposing one part of the agreement such as pricing terms and conditions to public attention can compromise the relationship between involved parties as well as complicate relationships with other parties. Therefore, regulatory review should carefully protect confidential information. Private party agreements should not be subject at all to regulatory review.

P9 -- Coordinate Regulatory Review and Oversight: Regulatory bodies, which have jurisdiction over demand response programs, must work expeditiously and cooperatively to remove barriers to implementation.

[55] Correspondence with Joel Gilbert, January, 2002.

The implementation of demand response programs can require the coordination and cooperation of multiple federal and state regulatory bodies. These include FERC, DOE, EPA, state PUCs environmental agencies, as well as RTOs, regulated distribution utility companies and aggregators. It is imperative that these groups work with a sense of urgency and with a common purpose. Such cooperation would go a long way to help eliminate impediments to and encourage the development of demand response programs and resources.

8.0 Recommended Regulatory Actions

The principles of demand response presented above provide a backdrop against which efforts to promote demand response should be judged. This section presents some specific recommendations for regulatory action.

A1 -- Stimulate better reporting on demand response resources.

There is too little knowledge about the number, type and participation in demand response programs. Key market participants such as LSEs, CSPs and others should be required to report on demand response activities. Such a process could be managed by the ISOs under FERC jurisdiction and state PUC cooperation.

Taking care to protect confidential information, the report, at a minimum, should document the amount of resources recruited for demand response and the amount actually realized. The report would document types of programs, numbers of participants, and other information to help educate parties and encourage the adoption of demand response resources.

An alternative to mandatory reporting would be voluntary reporting. Utility distribution companies report to the EIA on form 861 which could be modified to accommodate more information on demand response activity.

A2 -- Establish goals for demand response

Goals for demand response would focus efforts for multiple market participants. The goal could be set in terms of ISO peak resources. The ISO would document the level of resources available for demand response, although not necessarily called upon. The scope would include programs of both the ISO and others in its territory. Demand response resources would be defined comprehensively to cover the entire range of load reduction programs, dynamic pricing programs and distributed resource capabilities. The goal would not be mandatory but represent a target to stimulate participation. The goal could be set as a percent of ISO peak load for the subject year. Recommended goals are 10% in 2005 and 20% in 2010.

A3 -- Allow generous cost recovery for demand response.

Uncertainty about cost recovery for demand response programs has severely inhibited necessary investments. Given the significant benefits available from demand response programs, cost recovery should be assured. Since the technologies involved in demand response are changing rapidly, generous cost recovery helps insure state of the art systems are deployed.

A4 -- Fully integrate demand response at the outset to provide greater value.

Supply-side resources have historically been accorded significantly more attention than demand-side resources. There is a natural tendency to favor supply-side resources simply because the bulk of energy officials are so much more familiar with them. To the extent policies ignore demand response resources, they may be placed at a competitive and operational disadvantage well into the future. Therefore, it is important to include demand response resources as early as possible in system planning efforts and operations.

As an action item, FERC should identify "best practices" as starting points for the entire market, and with clear objectives in principle describing how demand response will be able to participate. Such actions will provide market certainty to encourage continued investment. Strong signals that demand response markets will be an important characteristic of any RTO will allow interested potential market entrants to make investment decisions with greater degrees of confidence and with sufficient lead-time to participate, on Day 1."[56]

A5 -- Improve standardization of interconnection rules.

Interconnection rules vary across jurisdictions, types of resources and nature of market participant. Some rules are unduly burdensome and limiting to demand response resources. There is value to standardizing in a way to promote open architecture software, common measurements and other specifications to encourage demand response resources.

FERC should assert its authority, at a minimum, by standardizing interconnection rules for the transmission system. With regard to interconnection standards for distribution systems, there are differences of opinion about the need and value, with some in support of and others reluctant to see a strong federal agency presence.

A6 -- Encourage examination of environmental rules to foster demand response resources.

Some demand response resources are heavily restricted by environmental rules. For example, emergency or backup generators represent a large potential demand response resource. In some jurisdictions emergency generators may be permitted to operate only after the power goes out at a facility, and not to prevent outages. In others, only natural gas fired generators are permitted to operate for economy based demand response purposes.

Many demand response resources, including distributed generation resources, are environmentally beneficial. On balance, the net affect of demand response resources is certainly positive for the environment.
It is highly desirable to take all practical steps for environmental improvements. It is likely that by viewing demand response resources as a portfolio or collectively, from an environmental perspective, greater deployment may be realized. Therefore, energy commissions should work

[56] E Cubed Company, "Comments of the E Cubed Company, LLC to RTO Week," Before the Federal Regulatory Commission, Docket No. RM01-12-000.

with environmental authorities to re-examine policies and encourage a comprehensive view of using energy and the environment wisely.

A7 -- Creatively phase-out price caps to encourage demand response.

Demand response resources are particularly effective in reducing price volatility of electric prices. To the extent volatility is restricted by regulatory as opposed to market forces, demand response resources are inhibited. Short run impacts occur when existing demand response resources are not called upon when they could be deployed to mitigate high market prices. Longer term impacts may occur by reducing investments in demand response resources. Regulatory restraint through minimizing the use of price caps would help stimulate greater use and investment in demand response resources. A good place to start is to phase-out hourly price caps.

A8 -- Establish rates based on costs including risk management costs.

Risk management or insurance costs have historically been embedded in regulated rates. Markets with retail choice have often mandated default service rates at levels that do not fully reflect the risk management costs. Yet, competitive market participants such as LSEs must reflect these costs in their prices. Furthermore, fixed prices mask price volatility, which some market participants are willing to share with their end-use customers in ways that can reduce energy bills significantly. The key to resolving this problem is explicit regulatory action to insure, at a minimum, that the provision of fixed-price electricity includes an insurance policy as well as the electricity commodity.

A9 -- Make decisions on metering timely with fair information ownership.

Advanced metering is essential to greater demand response participation. This is the case not only for load management programs but price responsive programs. In the absence of clear cost recovery policies, market participants are unwilling to make necessary investments. Advanced metering can occur with either a regulated monopoly or a competitive market, but it will likely not occur until regulators decide on the framework for such metering and infrastructure issues.

Related to the need for advance metering is the access to the information. In some jurisdictions, it has been determined the customer does not own the metering information. Accordingly, the customer does not necessarily have access to the data, whether immediately or later. Regulators should allow customers to not only access metering information but also take ownership for their own purposes.

Appendix 1 : Existing Demand Response Landscape[57]

Mass Market Programs

There are numerous demand response programs in place and more are being planned or implemented in both residential mass markets as well as among commercial and industrial customers. This section highlights different types of mass market programs.

Residential programs for demand response have been used for over twenty years, although participation has waxed and waned as utility objectives have shifted. The early tradition has been for mandatory participation among customers that enrolled. More recently voluntary programs are being deployed.

Direct Load Control

Direct load control (DLC) programs target customers with equipment that can be turned off or cycled for relatively short periods of time.[58] The most common applications are, in order of participation rates:

- residential central air conditioners,
- water heaters,
- swimming pool pumps, and
- electric space heaters with storage features.

Receiver systems must be installed on the customer equipment to enable communications from the utility and institute controls. Communications are often by radio signal from the utility. However, power line carrier is of growing interest as is the use of public or private wireless communication systems.

DLC programs are mandatory typically, once a customer elects to participate. Voluntary participation is now an option for some programs with more intelligent control systems and override capabilities at the customer facility. Of course, such voluntary behavior may be reflected in lower payments for participation.

Typically, the utility is authorized to cycle or shut-off a unit for a limited number of hours for a limited number of occasions. Cycling strategies for air conditioners range widely:

- 25% cycling or 7.5 minutes off out of 30 minutes,
- 33% cycling or 10 minutes off out of 30 minutes,
- 50% cycling or 15 minutes off out of 30 minutes, and

[57] Extracted and revised from "Peak Load Management or Demand Response Programs," Association of Energy Services Professionals International, August, 2001.
[58] Utilities with programs include Allegheny Electric Cooperative, Exelon (Commonwealth Edison), GPU, Exelon (PECO), PEPCO, and PSE&G. Utilities with terminated programs include Ameren (Union Electric) and SRP.

- 100% cycling or off all 30 minutes in each half hour.

Typically the unit is free to operate when not cycled off. Thus the resident is assured of some air conditioning under most schemes. A related issue is whether the fan continues to circulate air and help maintain comfort by being in the "on" position as opposed to the "automatic" position that is tied to the operation of the compressor. Most programs just prevent the compressor from operating thereby allowing the fan to circulate air in the home when customer has it set in the "on" position.

Smarter control systems have memories built-in to recognize how much the equipment has been running and are programmed to cycle at different frequencies so all participants provide similar load reductions. Of course some systems provide no load reduction where the unit is turned off during the curtailment period or the cycling equipment has been disabled by the customer, whether deliberately or not. Most programs factor such "free rider" effects into the calculations of benefits and costs.

Incentives to the customer are based on several factors including:

- type of unit under control such as air conditioner or water heater,
- degree of control such as 30% cycling or 100% off,
- the average amount of load reduction net of free rider effects, and
- the value of the load reduction to the utility.

Incentives are typically paid through monthly credits on utility bills. These may be just for the load control season or all year as a reminder of the customer's value to the utility. Customers typically do not have to pay for the equipment or installation of control systems.

Key issues include disrupting customer comfort and convenience. However, the presence of millions of households in these programs attests to their utility appeal and customer acceptance.

Demand Bidding or Buyback Programs

Demand bidding or buyback programs are available when the residential customer is willing to forego using electricity at a price. Typically these are voluntary programs since the customer has a choice about whether and how much to participate on any particular day.

These are very new programs that in many cases are still in the pilot test stage. One enabling technology is a programmable thermostat which controls the air conditioning and heat systems. The thermostat can be programmed to increase settings in the summer or decrease settings in the winter by various amounts. Furthermore, there is a transceiver in the thermostat to allow communication with the utility control center.

One current configuration is designed for direct load control where receipt of a utility signal causes the thermostat to shift to a higher setting in the summer. This has the effect of turning off the compressor on the air conditioner. Electric water heaters are also good prospects for direct load control.

The demand bidding or buyback configuration allows the utility to send price signals. If an air conditioning system is engaged, the thermostat can be programmed to adopt different settings depending on the price level offered by the utility. At a lower price the thermostat adjustment may be small and the compressor will only be off for a relatively short period. At a higher price the adjustment may be large and the compressor may not come on again for hours. The thermostats also have a notification feature to alert residents of calls for action as well as an override feature in case the customer chooses not to participate for the particular event.

Various internet based programs are also in development. Here the customer obtains information on buyback rates via internet connections and takes appropriate actions to manage peak loads, while selling its unused energy back as real-time prices.

A key issue for buyback programs is how sophisticated or complex to make the price signals. There is also the issue of verification to confirm some benefit was obtained when the thermostat and air conditioning system responded.

Time-of-Use Rates

Time-of-use (TOU) rates are designed to more closely reflect the utility cost structure where rates are higher during peak periods and lower during off-peak periods. Both voluntary and mandatory programs may be found.[59]

Voluntary programs allow customers to opt in and later opt out, although they must stay for an agreed upon period of time, such as one year. These programs favor people with lifestyles and equipment inventories using more energy during off-peak periods. This presents a serious issue for voluntary programs because utilities may experience revenue losses as only participants with favorable load profiles participate.

Mandatory programs are designed for whole segments of customers and all must participate. For example, all customers over a certain usage may be required to take energy under a TOU rate. Or all new customers may be placed under a TOU rate.

If rates are designed properly and customer behavior changes within reasonable expectations, utility revenues may be neutral under mandatory programs. That is, customers saving money under TOU rates would be offset by customers paying more. When behaviors change to reduce peak demand and shift usage to cheaper time periods, load factors are improved and, over time, all rates can be adjusted down as compared to without TOU rates.

Key issues involve metering, billing and customer education. Advanced meters are required typically at each home to record usage by time-of-day as opposed to measuring usage over the normal monthly billing cycle. Advanced meters require more sophisticated reading and calculating systems to translate the usage into bills for payment.

[59] Utilities include Allegheny Power, Cinergy, GPU, NYSEG, Exelon (PECO), PEPCO, and PSE&G.

Due to the internet, changes are taking place with TOU rate programs. Advanced meters can be tied into communication systems that allow customers to see energy usage as the month proceeds. Through personal computer connections with servers owned by utilities or their business partners, customers can determine costs and take actions to reduce or shift loads to cheaper times of the day or week.

Other key issues involve the definitions of peak and off-peak periods. Some utilities have two pricing periods per day, others three, and others four. Usually weekends and holidays are considered off-peak. A particularly challenging issue is what rates to charge in each rating period since various theories can be adopted to allocated fixed and variable costs among not only classes of customer but also periods of time.

Commercial/Industrial Program Options

Peak load management programs are also available for the commercial and industrial (C/I) class of customers. In fact, more variety exists for these kinds of programs.

Interruptible Programs

For decades, utilities offered interruptible programs for the primary purpose of system reliability.[60] Characteristics of interruptible programs were:

- large load reductions of at least 1 MW and usually including the entire facility,
- short notification to comply such as just an hour and as short as ten minutes,
- interruption could be required at any time of the day or day of the year,
- mandatory compliance,
- failure to perform resulted in huge penalties,
- maximum number of interruptions allowed during any year, and
- permanent discounts on electric bills.

Most participants tended to be industrial customers that could interrupt operations for a few hours or a shift. Common participants included those with operations in refining, melting, manufacturing, mining, food processing, and water treatment. Also participating were facilities served by backup generators that could carry all or large portions of the load such as hospitals and data centers.

However, many utilities rarely if ever interrupted these customers. So with the rate discount, such programs evolved more for purposes of economic development than for load management.

Related to the issue of mandatory compliance is the issue of severe penalties. For customers that do not interrupt as requested, utilities have provisions allowing significant penalties. It is no wonder customers drop out of interruptible programs when mandates for performance exceed expectations.

[60] Utilities with interruptible programs include Allegheny Electric Cooperative, Allegheny Power, Arizona Public Service, Exelon (Commonwealth Edison), NYSEG, Exelon (PECO), and PSE&G.

Curtailable Load Programs

To provide an option to the extremes of interruptible programs, utilities offer curtailable load programs (CLP).[61] One utility prefers the term "power down" for these programs. Key characteristics include:

- smaller load reductions expected such as 100 to 200 kW minimum, but as high as 500 kW or 1,000 kW to qualify;
- fewer number of curtailment requests such as 15;
- curtailment requests only during certain days and times, such as weekdays and between 11 a.m. and 7 p.m.;
- mandatory participation once an agreement has been reached;
- small penalties for failures to meet load reduction targets; and
- credits based on amount of load reduced and applied against standard tariffs;

Commercial facilities such as offices and retail can more easily participate and do. Those with backup generators can not only reduce lighting and air conditioning loads but also carry all or part of the remaining load themselves.

One program design option for curtailable load programs is whether to treat participants individually or collectively. Most programs approach facilities individually and reward them separately. However, some programs are set up as a cooperative. In this case the utility works with the facilities as a group, such as may be found in one geographical area.

There are many operational issues. But one particularly relevant issue for CLP is how to manage the limited number of hours and days for which curtailments may be exercised. If managers do not husband the curtailments sufficiently well, they may reach the last few weeks of the curtailment season with insufficient resources to call upon should they be needed. However, most utilities are more concerned about the issue of revenue losses during curtailment periods. As a result the end of the curtailment season is often reached without using all the allowed events, particularly in mild summer seasons.

Real Time Pricing

More utilities are offering pricing options based on time-of-use (TOU).[62] Some are standard time- of-use rates which are fixed for entire seasons with peak and off-peak prices. For example 8 a.m. to 8 p.m. on weekdays may be the peak period and cost twice as much as other times which are all considered off-peak, including weekends. TOU programs have been successful in promoting the use of load shifting technologies such as cool storage with ice or water.

---

[61] Utilities with curtailable progams include Allegheny Electric Cooperative, Allegheny Power, Ameren, Arizona Public Service, Cinergy, Exelon (Commonwealth Edison), GPU, Exelon (PECO), PEPCO, and PSE&G.
[62] Utilities with TOU programs include Ameren, Cinergy, Exelon (Commonwealth Edison), GPU, NYSEG, Exelon (PECO), PEPCO, and PSE&G.

A more refined alternative is real time pricing where prices vary hour by hour. Customers may volunteer to participate but must usually remain in the program for some specified period of time, such as one year. Program designs include:

- day ahead pricing with hourly costs,
- day of pricing with hourly costs, and
- voluntary load changes on part of the customer.

Sophisticated customers can tie the utility pricing scheme into their energy management system. Greater price differentials between high and low costs periods can automatically trigger greater shifts of energy usage.

More commonly, customers make decisions day to day. For example, some customers may choose to pre-cool a facility in the morning when rates are lower and coast through at a higher temperature in the afternoon when rates are higher. This may work for normal occupancy or use of a store, office or factory. However, if the facility is operating at a high occupancy or capacity, customers may choose to "buy-through" during premium cost periods and not change operations.

There can be significant savings when power is inexpensive. The risk is whether the cheap hours are offset by expensive hours. Utilities claim that most customers come out ahead and once in the program want to remain.

However, such programs seem to work better in states with monopoly utilities still, since rates are regulated and price fluctuations are more predictable. States with deregulation have not found real time pricing as popular due to the potential for wild price fluctuations.

Demand Bidding or Buyback Programs

One disadvantage of real time pricing is that the customer is stuck in the program for an entire year. If prices skyrocket not only for a few hours but for many days, there is a real financial risk.

Under demand bidding or buyback programs, the customer remains on a standard rate but is presented with options to bid or propose load reductions in response to utility requests.[63]

How to determine offering prices is one of the issues on demand bidding programs for utilities. There are four general pricing schemes.

- A fixed percentage of the wholesale spot market price is offered to customers. The percentage has been found to vary from utility to utility in part due to whether they wish to recover administrative costs and earn a margin.
- A variable percentage of the wholesale spot market prices is offered by some utilities. The percentage varies according to system and market conditions.

[63] Utilities with demand bidding include Allegheny Power and GPU.

- A fixed price whereby the customer determines at the beginning of the program what amount of load it will provide at a specified price. Then the utility can call on those customers agreeing to the lowest buyback prices first and call on others as needed.
- A variable price which the customer determines. The variable price may be determined for each event by the customer or may be within a range agreed to with the utility. When the customer bids in response to the utility request, the utility can rank the bid loads and prices in order to decide how much to take and from which customers.

In addition to utilities offering to buy back energy on the basis of time, refinements are also being made on the basis of location. Congestion can occur on the transmission and distribution facilities of utilities. So rather than calling for capacity reductions solely for generation purposes, utilities can call for load reductions in certain neighborhoods and regions. Furthermore, the utility can offer more incentives in some regions than other regions for the same period of time in order to balance generation capacity needs with transmission and distribution needs.

To accommodate the load and pricing options, utilities are forming alliances with power exchanges. Similar in concept to a stock exchange, the power exchange facilitates transactions by matching offers to buy power with offers to sell power. This raises issues of insuring the various parties live up to the agreements regarding settlement of energy and financial obligations.

Appendix B: Bibliography

Adams, Nathan: “Getting the Right Response,” *Electric Perspectives*, November/December, 2001.

Adels, Peter and Stephen Fernands: “Comments on Behalf of Citizens for Pennsylvania’s Future Concerning the Initial Proposals of Commission Staff For DSR Initiatives,” August 1, 2001.

Association of Energy Services Professionals International: “Peak Load Management or Demand Response Programs: A Policy Review,” August, 2001. www.aesp.org

Braithwait, Steven and Ahmad Faruqui:“The Choice Not to Buy: Energy Savings and Policy Alternatives for Demand Response,” *Public Utilities Fortnightly*, Vol. 139, No. 6, March 14, 2001.

Briedenbaugh, Aaron: “New York 2001 Load Reduction Programs and 2002 Initiatives,” Vermont Public Service Board Workshop: Northeastern Demand Reduction Programs, Price Responsive Load Coalition, October 26, 2001.

Brock, Jon T. and J. Christopher Perdue: “Information Technology in a Retail World,” *Electric Perspectives,* September/October, 2001.

Buechler, John P. and others: “Feasibility Study for a Combined Day-Ahead Market in the Northeast,” Draft, for ISO-New England, NewYork ISO, and Ontario IMO, January 19, 2001, www.iso-ne.com

Burns, Sandra and George Gross: “Value of Service Reliability,” *IEEE Transactions on Power Systems*, Vol. 5, No. 3, August 1990, pp. 825-834.

C Three Group: *Load Management 2001-Balancing Customers, Regulators and Energy Demand,”* November, 2001. (available from The C Three Group, fee)

California ISO: “Market Design 2002 Project,” January 8, 2002. www.caiso.com.

California ISO: “Demand Response Program Processes,” October 18, 2001. www.caiso.com

California ISO: “Demand Response Program Overview/Processess,” May 21,2001. www.caiso.com

California ISO: “List of California ISO Demand Response Participants,” March 28, 2001. www.caiso.com

Caves, Douglas W. and Kelly Eagin and Ahmad Faruqui: “Mitigating Price Volatility by Connecting Retail and Wholesale Markets,” *Electricity Journal*, April 2000.

Charles River Associates: “TOU Pricing for Mass Markets,” (2002).

Chartwell, *Chartwell Load Management Report*, Chartwell and Xenergy, November, 2001. (available from Chartwell, fee)

Christianson, Robbin: “What Utilities Love and Hate About AMR,” *Public Utilities Fortnightly*, AMR Supplement, 2000. pp.26-34.

Chuang, Angela and Felix Wu: “Capacity Payments and the Pricing of Reliability in Competitive Generation Markets,” *Proceedings of the Hawaii International Conference on System Sciences*, January 4-7, 2000.

Colledge, Justin A. and Jason Hicks, James B. Robb and Dilip Wagle: “Power by the Minute,” *McKinsey Quarterly*, Number 1, 2002. www.mckinseyquarterly.com.

Douglas, John: “The Future of Metering,” *EPRI* Journal, March/April, 1998.

E Cubed Company: “Comments of the E Cubed Company, LLC to RTO Week,” Federal Energy Regulatory Commission, Docket No. RM01-12-000

EPRI: *Demand Trading Workshop*, December 2001.

EPRI: *Day-Ahead/Hour-Ahead Forecasting for Demand Trading: A Guidebook*, EPRI 1006016, December 2001.

EPRI: *Load Management Database*, December 2001

EPRI: “Demand Trading Toolkit,” EPRI 1006017, 2001. www.epri.com (available to EPRI members)

EPRI: “The Western States Power Crisis: Imperatives and Opportunities,” June 25, 2001, www.epri.com.

EPRI: *Custom-ER Billing Engine (CBE)*, (TR-114254), March 2000.

EPRI: *Methods for CIS and Billing Evaluation*, (TR-112067), February 1999.

EPRI: *COSS Service Bureau*, (TR-111924), December 1998.

EPRI: *Development and Demonstration of Energy Management Control Strategies for Automated Real-Time Pricing*, (TR-111365), October 1998.

EPRI: *Automated CO2 and VOC-Based Control of Ventilation Systems Under Real-Time Pricing*, (TR-109117), October 1998.

EPRI: *Small Commercial Customer Energy Management System Demonstration Project,* (TR-110183), September 1998.

EPRI: *Increasing the Yield of Real-Time Pricing: Kansas City Power & Light's Real-Time Pricing Innovations,* (TR-110747), August 1998.

EPRI: *Customer Load Response to Spot Prices in England: Implications for Retail Service Design*, (TR-109143), November 1997.

EPRI: *EPRI Technologies Make Real-Time Pricing A Winner at Con Edison Customer*, (IN-107182), May 1997.

EPRI: *Development of Energy Management Strategies for Automated Real-Time Pricing: Control System Enhancements for Thermal Energy Storage (TES) and Modulating Building Loads,* (TR-105501), May 1996.

EPRI: *Reaping the Benefits of RTP: Georgia Power's RTP Evaluation Case Study,* (TR-105044), December 1995.

EPRI: *Fielding a Real-Time Pricing Program: Pennsylvania Power and Light Case Study,* (TR-105042), August 1995.

EPRI: *Real-Time Pricing Quick Start Guide: Fielding Real-Time Pricing,* (TR-105045), August 1995.

EPRI: *Application of Interruptible and Curtailable Electric Service in Foundries,* (CR-105046), March 1995.

EPRI: *Quick Starting a Retail Market Management Initiative — Real-Time Pricing: A Georgia Power Company/EPRI Collaborative Project,* (TB-101798), April 1993.

EPRI: *EPRI Demonstrates Real-Time Pricing and Energy Management System at New York City Hotel*, (IN-101200), December 1992.

EPRI: *Customer Response to Interruptible and Curtailable Rates*, Volumes 1-3 (EM-5630), March 1988.

Edison Electric Institute: "Load Management Benchmarking – 1998 Data," (Based on DOE data; free to members). www.eei.org.

Exelon: "Exelon Draft Proposal for PJM Demand Response Programs," Nov. 21, 2001.

Faruqui, Ahmad and Joe Hughes and Melanie Mauldin: "Real-Time Pricing in California:R&D Issues and Needs," Charles River Associates for California Energy Commission, January 8, 2002.

Faruqui, Ahmad: “California’s Travails,” Guest Editorial, *The Electricity Journal*, August-September 2001, pp. 65-67.

Faruqui, Ahmad: “When Will I See Profit?” *Public Utilities Fortnightly*, July 1, 2000.

Faruqui, Ahmad: “Fighting Price Wars.” *Harvard Business Review*, May-June 2000.

Faruqui, Ahmad and Kelly Eakin, editors: *Pricing in Competitive Electricity Markets*, Kluwer Academic Publishing, 2001.

Faruqui, Ahmad and Kelly Eakin: “Bundling Value-Added and Commodity Services in Retail Electricity Markets,” *Electricity Journal*, December 2000.

Faruqui, Ahmad and Kelly Eakin: “Summer in San Diego,” *Public Utilities Fortnightly*, September 15, 2000.

Faruqui, Ahmad and Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, “Getting out of the dark,” *Regulation*, Vol. 24, No. 3, Fall 2001.

Faruqui, Ahmad and Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf: “California Syndrome,” *Power Economics*, May, 2001.

Faruqui, Ahmad and Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf: “Analyzing California’s Power Crisis,” *The Energy Journal*, Vol. 22, No. 4, 2001.

Faruqui, Ahmad and J. Robert Malko: editors, *Customer Choice: Finding Value in Retail Electricity Markets*, Public Utilities Reports, Inc., 1999.

Federal Energy Regulatory Commission: “Concept Discussion Paper for an Electric Industry Transmission and Market Rule,” Staff Paper, December 17, 2001.

Gilbert, Joel: “Managing the Ups and Downs,” *Electric Perspectives,* March/April,2001.

Gilbert, Joel: “Market-Flexible Load Shapes: Adding the Demand Side to the Risk Management Portfolio,” (2000).

Gilligan, Donald: “Grading 2001’s ISO Demand Response Programs,” *Energy User News*, November 2001.

Harris, Louis: “Thorny Details: Despite Its Shining Promise, Distributed Generation Confronts a Regulatory Thicket of Technical Questions and Competitive Issues,” *Electric Perspectives,* March/April, 2001.

Hirst, Eric: “The Financial and Physical Insurance Benefits of Price-Responsive Demand,” January 2002, 11 pp.. www.ehirst.com.

Hirst, Eric: "The California Electricity Crisis: Lessons for Other States," Edison Electric Institute, July 2001. www.ehirst.com.

Hirst, Eric: "Price-Responsive Demand in Wholesale Markets: Why is So Little Happening?" *The Electricity Journal* 14 (4), 25-37, May 2001.

Hirst, Eric: "Price-Responsive Demand: Key to Competitive Electricity Markets," *Public Utilities Fortnightly,* 34-41, March 1, 2001.

Hirst, Eric: "Real-Time Performance Metrics for Generators Providing the Regulation Ancillary Service," *The Electricity Journal* 14(3), 48-55, April 2001.

Hirst, Eric: "Real-Time Pricing Could Tame the Wholesale Market," *Electric Perspectives*, 26(2), 58-61, March/April, 2001.

Hirst, Eric and Brendan Kirby: "Metering, Communications and Computing for Price-Responsive Demand Programs," *Electric Light and Power*, 78(8), 17-18, August 2001.

Hirst, Eric and Brendan Kirby: "Transmission Planning for a Restructuring U.S. Electric Industry," Edison Electric Institute, June 2001. www.ehirst.com

Hirst, Eric and Brendan Kirby: "Retail-Load Participation in Competitive Wholesale Electricity Markets," Edison Electric Institute, January 2001. www.ehirst.com

Hoffman, Steve and Rita Renner: "Taking Advantage of Real-Time Pricing," *EPRI Journal*, March/April 1997), pp 17-23.

ISO New England: "Load Response Program Manual," July 17, 2001. www.iso-ne.com

ISO New England: "Load Response Seminar for Load Servers," April 5, 2001. www.iso-ne.com

ISO New England: "Group Load Curtailment Program: Pilot Project Evaluation," 2001. www.iso-ne.com

ISO New England: Load Response Opportunities Conference, papers by Conner, Gilbert, Rosenstock, Schivley, James, Lawrence, Shalaby, Whitley, Besser, Leach, Kormos and Rabl, October, 2000. www.iso-ne.com

Jaske, Michael R. and Arthur H. Rosenfeld: "Developing Demand Responsiveness in California's Energy Markets," 76th Annual WEA Conference, July 2001.

Keller, Leland: "Distributed Generation Aggregation, Dispatch and Control," 3rd Annual International Symposium on Distributed Energy Resources, E Source, November 2, 2001.

Kilbourne, Becky and Robert Maxant: "Making Markets Work: How ISO Rules Still Cause Problems," *Public Utilities Fortnightly* 140 (1), 28-31, January 1, 2002.

King, Chris: “How Competitive Metering Has Failed,” *Public Utilities Fortnightly* 139 (21), 30-34, November 15, 2001.

King, Chris: “Compendium of Real Time Pricing and Time of Use Studies and Reports,” American Energy Institute, www.americanenergyinstitute.org.

Knaplund, Paul: “Load Response Program,” ISO New England, June 6, 2001.

Lesser, Jonathan A., and Stephen L. Derby and William Clarke: “Resource Planning: the Need for a New Approach,” *Public Utilities* Fortnightly 140 (2), 20-27, January 15, 2002.

Levesque, Carl J.: “Regulators’ Forum: Can FERC and States Unite?” *Public Utilities Fortnightly* 139 (21), 14-27, November 15, 2001.

Levesque, Carl J.: “Distributed Generation: Doomed by Deployment Details?” *Public Utilities Fortnightly*, February 1, 2001, pp. 47-51.

Lively, Mark: “Saving California with Distributed Generation,” *Public Utilities Fortnightly* 14-20, June 15, 2001.

Lively, Mark: “Distributed Generation: Setting a Fair Price in the Distribution Tariff,” *Public Utilities Fortnightly* 26-38, October 15, 2000, 26 - 38.

Long Island Power Authority: “Demand Reduction Programs,” LIPA, September 27, 2001.

Malme, Ross, and Pete Scarpelli: “The Benefits of Load Response Solutions to Manage Transmission Congestion,” Submitted to the U.S. Department of Energy, The National Transmission Grid Study 2001 (NTGS2001), September 26, 2001. www.retx.com

Malme, Ross: “Planning Successful Regional Demand Programs,” 2001. www.retx.com

McKinsey and Company: “The Benefits of Demand-Side Management and Dynamic Pricing Programs,” May 1, 2001.

Merilatt, Dan and David Eggart and Lisa Esser, “Residential Customers Embrace the Power to Choose,” *Transmission and Distribution World*, February 2001.

META Group: “Energy Management + Price-Responsive Demand = Effective Customer Choice,” Trend Teleconference, July 19, 2001.

Moore, Taylor: “Energizing Customer Demand Response in California,” *EPRI Journal*, Summer, 2001.

Moore, Taylor: “Emerging Markets for Distributed Resources,” *EPRI Journal*, March/April, 1998.

Neenan Associates: "NYISO PRL Program Evaluation: Executive Summary," New York Independent System Operator, January 15, 2002, 31 p. www.nysio.com.

Neenan Associates: "Effects of NYISO PRL Programs on New York Electricity Markets," December 6, 2001.

New England Power Pool: "New England Power Pool; FERC Docket No. ER02-000: Revisions to NEPOOL Market Rules to Modify, Enhance and Extend the Load Response Program," December 28, 2001, pp 60+.

New York Independent System Operator: "Compliance Report in Docket No. ER01-3001-000," Filed with FERC, December 4, 2001, pp. 20+.

Newton, Charles: "From DSM to Demand Response," *Electric Perspectives,* November/December, 2001.

PJM: "PJM Load Response Program – Strawman," Demand-Side Response Working Group, as of January 9, 2002. pp 31.

PJM: "Report on the 2001-2002 PJM Customer Load Reduction Program," surmised date, January 2002.

PJM: "PJM Proposed Demand Response Program: PJM Day-Ahead and Real Time Demand Response Program Manual," November 26, 2001. www.pjm.com.

PJM Members Committee: "PJM DSR Principles Endorsed by Members Committee," undated, 2 pp.

Patton, David B.: "An Assessment of Peak Energy Pricing in New England During Summer 2001," ISO New England, November, 2001. www.iso-ne.com

Peak Load Management Alliance: Fall Conference, 2001, Presentations on NYISO, NEISO, CAISO, others. www.peaklma.com.

Peak Load Management Alliance: Spring Conference, 2001, Presentations by Alexander, Capstone, Allegheny, GPU, AES, CAISO, PJM, Ercot, NEISO, NYISO Hirst, Lenssen, Cherian, James. www.peaklma.com.

Peak Load Management Alliance: Fall Conference, October, 2000, Presentations by Gilbert, Miller, Brown, Violette, Stathis, Joyce, Smith, Anderson, Uhr, Darnell, Rabl and Smith, Gregerson, Puckett and Scarpelli. www.peaklma.com.

Peak Load Management Alliance: Spring Conference, June, 2000, Presentations by Barkovich, Dyment, Frandsen, Gilbert, Hall, Leach, LeBlanc, Rabl, Rosenstock, Stizler, Smith, Weaver and White. www.peaklma.com.

Price Responsive Load Coalition: "Comments of Price Response Load Coalition on Mediator's Report," Federal Energy Regulatory Commission, Docket No. RT01-99, October 8, 2001.

Price Responsive Load Coalition: "Draft PRLC Responses to NE RTO Business Plan Questions, Appendix A-2 – Demand Response," undated.

Price Responsive Load Working Group: Meeting Minutes, October 21, 2001.

RETX: "Taming Price Volatility with the Next Generation of Load Management. www.retx.com

Radford, Bruce W.: "Rules of the Grid: Transmission Policy and Motives Behind It," *Public Utilities Fortnightly*, December 2001.

Radford, Bruce W.: "Rising Power Prices: The Metering Industry's Big Break?" *Public Utilities Fortnightly*, October 1, 2000. pp.26-32.

Radford, Bruce W.: "AMR Today: Sorting Fact from Fiction," *Public Utilities Fortnightly*, AMR Supplement 2000. pp.8-17.

Ringelstetter, Sandra L.: "New England Peaking Resources Cost," December 10, 2001. www.iso-ne.com

Rosenstock, Steve: "Benchmarking for Load Management 2001," Edison Electric Institute, November 2001.

Rosenstock, Steve: "Demand Response Programs – A National Accounts Perspective," Edison Electric Institute, November 2001.

Rosenstock, Steve: "Benchmarking for Load Management," for Edison Electric Institute at Peak Load Management Conference, June 5, 2000.

Rosenstock, Steve: The Future of Load Management," Edison Electric Institute, October 16, 2000.

Rosenstock, Steve: "Value Propositions for Load Management Programs in a Restructured Electricity Market," Peak Load Management Alliance Conference, Edison Electric Institute, October, 1999.

Smith, William M.: "Demand Trading," *Public Utilities Fortnightly*, March, 2002.

Smith, William M.: "Digital Mobility," *Public Utilities Fortnightly*, 2001.

Smith, William M.: "The Next Killer App: Load Management, Only This is for Real," *Public Utilities Fortnightly* 30-36, August, 2000.

Smith, William M.: "Demand-Side Management," *International Energy Conservation Symposium*, 1988.

Smith, William M.: "Integrated Value-Based Planning" *IEEE Transactions*, 1988.
Smith, William M.: "Communities Cut Usage, Earn $100,000" *Electrical World*, 1983

Tabors, Richard D.: “Institutional Alternatives for Transmission System Operations,” Tabors, Caramanis & Associates, March, 1999. 12 pp.

Taub, Steven: “The Information Engine (AMR As Information Engine)” *Electric Perspectives, September/October, 2000.*

Thurston, Charles W.: “What’s Stalling AMR?” *Public Utilities Fortnightly*, AMR Supplement 2000, pp.18-25.

Uhr, C. William: “Retail Time-Based Electricity Pricing,” December 15, 2001.

Uhr, C. William: “Implementing Residential Coincident-Peak Pricing,” 12th National Energy Services Conference, December 4, 2001.

Denise Worhach: “AMR Outlook: The Analysts’ View,” *Public Utilities Fortnightly*, AMR Suppplement 2000, pp. 37-42.

Wiebe, Michael and Gary Fauth: “AMR: Don’t Wait,” *Electric Perspectives*, September/October, 2001.

Filename: Principles for Regulatory Guidance.doc
Directory: C:\Documents and Settings\kmcinvai\Desktop\working stuff\electric_restruct\New Folder 1 - handouts - done\done
Template: C:\Documents and Settings\kmcinvai\Application Data\Microsoft\Templates\Normal.dot
Title:
Subject:
Author: Larry Barrett
Keywords:
Comments:
Creation Date: 2/15/2002 2:41 PM
Change Number: 3
Last Saved On: 2/20/2002 12:35 PM
Last Saved By: kmcinvai
Total Editing Time: 2 Minutes
Last Printed On: 2/20/2002 12:36 PM
As of Last Complete Printing
Number of Pages: 49
Number of Words: 14,990 (approx.)
Number of Characters: 85,443 (approx.)